

Historic and Current Application of Well Stimulation Technology in California

*Authored by
Preston Jordan (LBNL)
Matthew Heberger (PI)*

This chapter reviews the application of each of the three well stimulation technologies (WST) described in Chapter 2 for onshore oil production in California, and includes a review of the history of each technology's application, estimates of current deployment rates for each technology and the stimulation-fluid volumes and types typically utilized in California.

Hydraulic fracturing has been applied in numerous onshore oil fields in California for decades, starting in 1953. Intensive use of the technique commenced in the late 1970s and early 1980s. This was shortly before oil production in the state peaked (California Division of Oil, Gas, and Geothermal Resources (DOGGR) 2010). Data indicate hydraulic fracturing of 100 to 150 wells per month is a reasonable estimate of current activity. This amount of activity is the same as was occurring in the years prior to the recent recession. Most hydraulic fracturing currently occurs primarily in a few fields in the southwestern portion of the San Joaquin Valley in Kern County. In contrast to hydraulic fracturing predominantly of horizontal wells in the low-permeability Eagle Ford reservoir in Texas and Bakken in North Dakota, hydraulic fracturing of reservoirs in California occurs primarily in vertical wells requiring correspondingly smaller volumes of hydraulic fracturing fluid. This is in part because vertical wells have shorter treatment intervals than horizontal wells. It is also in part because gel, predominantly cross-linked, is used almost exclusively in California as compared to less viscous gels and slickwater in the other locations. The volumes per treatment length of less viscous fluids are typically up to several times the volumes used of cross-linked gel.

Based on available data, matrix acidizing has occurred in just a few fields, and more recently in just one field. A few tens of wells per month may be matrix acidized using combinations of hydrochloric and hydrofluoric acid. Recent data indicate all of this activity occurs in one field in the southwestern portion of the San Joaquin Valley in Kern County. The average acidizing fluid volume per well is a third to a fifth of the average hydraulic fracturing fluid volume in California. However, the average fluid volume per length of well treated is one half to two thirds of that used for hydraulic fracturing.

Acid fracturing generally uses hydrochloric acid in carbonate reservoirs, of which there are few in California. Those that do occur tend to be naturally fractured and no record of the use of acid fracturing in these reservoirs was identified. There is a recent record of acid fracturing of three wells using a hydrochloric and hydrofluoric acid combination. These are located in the same field as all recent matrix acidizing activity. The total fluid volume per well is similar to that for hydraulic fracturing, but the fluid volume per length of well treated implied by the available data is less than half that for matrix acidizing and a third to a fourth of that for hydraulic fracturing.

Section 2 explains that horizontal drilling technology is integral to hydraulic fracturing practice in many locations. Consequently, this section begins by considering the application of horizontal wells in California. The combination of horizontal wells and hydraulic fracturing in unconventional plays like the Eagle Ford and Bakken (primarily in Texas and North Dakota, respectively) has provided for economic development of those resources. However, horizontal wells can be used with or without well stimulation, as discussed in the next section. Discussion of horizontal wells is followed by discussion of well stimulation history and practice in California.

3.1 Horizontal Wells

In California, horizontal wells are used with and without well stimulation. This section discusses the historic application of horizontal wells without well stimulation followed by an assessment of recent horizontal well installation activity. Historic and recent stimulation of horizontal wells is discussed in Section 3.2 regarding hydraulic fracturing.

3.1.1 Historical Horizontal Well Utilization

The first horizontal-well-drilling technology was developed in the 1920s, but the immaturity of the technology led to only periodic use until the mid-1980s. By that time, the technology had been sufficiently developed such that the number of horizontal well installations for onshore oil production increased until the 1990s, when they became common (Ellis et al., 2000). Many thousands of horizontal wells had been installed in the United States by the mid-1990s (Joshi and Ding, 1996). The following is a review of the use of horizontal wells in California. Note that all of the fields mentioned in the discussion are located in the mid- to southern San Joaquin Valley.

Horizontal wells of a sort were drilled in the Kern River field in the early 1980s, but horizontal drilling technology had not yet reached maturity (Dietrich, 1988). Rather than advancing the horizontal lateral by turning a boring from vertical (as described in Section 2.2.2), the horizontal borings were drilled straight out in eight equiangular directions from within a large shaft excavated in the field. Production from these wells was below anticipated, and operation of the installation ended after recovering an additional 2.5% of the oil in place.

Horizontal wells as described in Section 2.2.2 have a number of applications in oil production (Ellis et al., 2000). They can have greater contact area with the petroleum-containing reservoir in near-horizontal layered geologic systems. In thinner reservoirs, vertical wells may not produce a volume of oil sufficient to make the well economic due to the short contact length between the well and the reservoir. Horizontal wells may be economic in these situations because they have a longer contact length with the reservoir, and so may produce a volume of oil that is sufficiently larger to make the horizontal well economic. Horizontal wells can also more readily intersect more natural fractures in the reservoir that may conduct oil, owing not only to their intersecting more of the reservoir than a vertical well, but also because fractures are typically perpendicular to rock strata, and so are nearly vertical in near-horizontal strata.

Horizontal wells can parallel water-oil or oil-gas contacts and so can be positioned along their length to produce more oil, without drawing in water or gas, than is possible from a vertical well. Due to their orientation parallel to geologic strata, horizontal wells can improve sweep efficiency during secondary or tertiary oil recovery, which involves the injection of other fluids, such as steam, to mobilize oil to a production well. A horizontal well also provides for more uniform injection to a particular stratum. On the production side, a horizontal well provides a more thorough interception of the oil mobilized by the injection. Vertical wells are more readily bypassed by mobilized oil due to variation in the permeability of the reservoir rock. Similar to being better positioned to intercept oil mobilized by injection, horizontal wells are also better positioned to intercept oil draining by gravity through a reservoir.

In California, horizontal wells have been used to access thin reservoirs, provide a more uniform distribution of steam injected to mobilize viscous oil, and better intercept oil draining by gravity. An example of a thin reservoir development is the installation of a horizontal well in a Stevens Sand layer of the Yowlumne field— a layer too thin to be developed economically using vertical wells. It was completed in 1991 at a true depth of over 3400 m (11,200 ft) with a 687 m (2,252 ft) lateral. The well tripled the production rate from the previous vertical wells in the reservoir (Marino and Shultz, 1992).

The use of horizontal wells for the second purpose, to improve the efficiency of steam injection for oil recovery began in the early 1990s. Steam injection reduces the viscosity of highly viscous oil, allowing it to flow more readily to production wells. For example three horizontal wells were installed in 45° dipping (tilted) units with a long history of steam injection in the Midway Sunset field. Two of the wells were installed with 121 m (400 ft) sloping laterals. They produced a volume of oil two to three times that of the nearby vertical wells, but these horizontal wells cost two to three times as much as vertical wells and so did not provide an economic benefit. A third horizontal well with a longer horizontal lateral of 213 m (700 ft) produced six times more oil than nearby vertical wells and so was more economically successful (Carpenter and Dazet, 1992).

Horizontal wells were also installed in a shallow, tilted (dipping) geologic bed in the Coalinga field in the early 1990s. Steam injection with oil production via vertical wells started in this zone in the late 1980s. The horizontal wells were installed in the same reservoir but deeper along the tilted bed. The wells were initially operated with steam cycling. This process entails injecting steam for a period, then closing the well to let the steam continue to heat the oil and reservoir, then opening the well and producing oil. However, the increase in production resulting from steam cycling was lower than expected. Vertical wells for continuous steam injection were subsequently installed shallower along the tilted bed from the horizontal wells. This resulted in a large sustained production rate that justified the horizontal wells, which led to considering further opportunities for installing horizontal wells in the Coalinga field (Huff, 1995).

By the late 1990s, horizontal well installation projects for production of shallow oil, using vertical steam injectors, involved tens of wells each. Nearly a hundred horizontal wells were installed in shallow sands containing heavy (viscous) oil in the Cymric and McKittrick fields from the late 1990s to early 2000s. These wells were installed in association with vertical wells that injected steam to reduce the viscosity of the oil by heating, allowing it to flow to the horizontal wells. The wells were installed in phases, allowing optimization with each phase that reduced the cost per well by 45% by the last phase (Cline and Basham, 2002). By the late 2000s and early 2010s, installation programs in reservoirs with steam injection involved as many as hundreds of wells. For instance, over 400 horizontal wells were installed in the Kern River field between 2007 and 2013, targeting zones identified with low oil recovery to date. These wells provided a quarter of the field's daily production (McNaboe and Shotts, 2013).

The third application of horizontal wells in California is for more efficient production of oil by gravity drainage. A prominent example of this is the installation of horizontal wells in a steeply dipping (60° from horizontal) sandstone reservoir in the Elk Hills field. Pressure to produce oil from this zone was maintained by injection of natural gas updip in the reservoir. The position of the gas-oil contact grew deeper as oil production proceeded. Production from vertical wells in the oil zone was reduced to limit the amount of overlying gas they drew in, which then had to be re-injected. The wells were also reconfigured periodically to move the top of the interval from which they produced to greater depths (Mut et al., 1996).

The first horizontal well in this reservoir was installed in Elk Hills in 1988; the second in 1990. The wells' laterals were installed 12 m (40 ft) above the oil-water contact and about 76 m (250 ft) downdip of the gas-oil contact. This allowed production rates multiple times that from the adjacent vertical wells without drawing in the overlying gas or water from below. Production was also more constant over time compared to the necessarily declining rates from the vertical wells (Gangle et al., 1991); production from one of the first two wells remained constant for at least five years (Gangle et al., 1991). Given the successful production from these wells, another 16 had been installed by early 1995 (Mut et al., 1996).

3.1.2 Recent Horizontal Well Installation

The GIS data files made available by DOGGR regarding oil, gas, and geothermal wells in California (DOGGR, 2014a) include the county and field in which the well is located, the date drilling was initiated, and whether the well was vertical (listed as “not directional” in the file), directional, horizontal, or had an unknown path. Review of a sample of recent well records available from DOGGR for directionally drilled wells indicates they are typically near-vertical in the reservoir, with the directional drilling employed primarily to offset (shift) where the well encounters the reservoir relative to the point from which it is drilled.

Of the more than 5247 wells with a drilling initiation date in 2012 or 2013, 85% list the type of well path. A total of 315 of these wells are listed as horizontal, which is 7% of the wells with a known path. Over 91% of the wells identified as horizontal are located in Kern County, and 68% are in the fields discussed in this section or indicated as having horizontal wells in Section 3.2.1 (on the history of hydraulic fracturing). The Kern River field alone contained 47% of the wells identified as horizontal. All but three of the horizontal wells—over 99%—were in pre-existing fields as defined by DOGGR. The three outside pre-existing fields were in Kern County. So in sum, a small percentage of recently installed wells in California are horizontal, the vast majority of these are in Kern County, and almost all are in pre-existing oil fields rather than in new development areas.

3.2 Hydraulic Fracturing

3.2.1 Historical Use of Hydraulic Fracturing

The earliest fracturing reported in California dates back to 1953 in the Cymric field of the San Joaquin basin—according to DOGGR (1998) — and in the Brea-Olinda and Esperanza fields in the Los Angeles basin—according to Ghauri (1960). The technique was applied in other fields, such as the Buena Vista, Sespe, and Holser fields, in the following decades (Erickson and Kumataka, 1977; Norton and Hoffman, 1982). This early fracturing was accomplished with water- and oil-based fluids, both gelled and ungelled (Ghauri, 1960; Erickson and Kumataka, 1977). Ungelled, oil-based fluids provided the best results (Erickson and Kumataka, 1977; Norton and Hoffman, 1982). These applications were typically in low-permeability sandstone to shale (Ghauri, 1960; Erickson and Kumataka, 1977; Norton and Hoffman, 1982).

The first reported hydraulic fracturing of diatomite in California occurred in the late 1960s. Diatomite is a high-porosity, low-permeability rock consisting primarily of siliceous matter from diatoms, a type of marine algae. It is a reservoir rock containing oil in some fields (see more information in Section 4). Multistage fracturing from vertical wells successfully treated a 230 m (750 ft) vertical interval of diatomite in the Lost Hills field. Oil production increased relative to untreated wells, but only for two months. The increase was insufficient for the treatments to be economic (Yarbrough et al., 1969). Further

development of the technique in the diatomite led to its economically viable application by the late 1970s (Emanuele et al., 1998). Hydraulic fracturing of the diatomite in the San Joaquin Valley became relatively standardized within companies in the following decades, but practice varied from company to company (Allan et al., 2010).

The first successful production resulting from hydraulic fracturing in diatomite at the South Belridge field occurred in 1977 (Allan et al., 2010). By the early 1980s, one operator had hydraulically fractured hundreds of wells in the diatomite at South Belridge, as well as at several other fields (Strubhar et al., 1984). Water flooding of the diatomite in the South Belridge field started in the late 1980s, and hydraulic fracturing of both injectors and producers was standard practice (Yang, 2012). Water flooding involves injection of water into an oil reservoir to drive more oil to the producing wells.

The first horizontal wells were installed in the South Belridge field in the early 1990s. They were installed in permeable sands with oil overlying the diatomite and (therefore) were not hydraulically fractured; they did not produce sufficiently. Horizontal wells were subsequently installed in the diatomite and hydraulically fractured in stages. Vertical wells were found to be a better approach in zones with oil thicker than 137 m (450 ft) toward the center of the field. Horizontal wells were installed in the thinner oil zones consisting of diatomite recrystallized to opal CT (see Section 4.2.2) along some margins of the field. Orienting the wells for longitudinal fractures was found to result in greater production (Allan et al., 2010). (As described in Chapter 2, a longitudinal fracture is oriented in the same direction as, rather than perpendicular to, the horizontal well from which it extends, which is generally an advantage in relatively more permeable formations.)

The development history of the diatomite in the Lost Hills field is similar to that in the South Belridge field. Hydraulic fracturing was implemented in the Lost Hills field in 1976 (Fast et al., 1993); fracturing was from vertical wells (Strubhar et al., 1984; Hansen and Purcell, 1989). In the early 1990s, water flooding of the diatomite in the Lost Hills field was implemented to improve production and reduce ground subsidence. The vertical injectors and producers were hydraulically fractured (Wilt et al., 2001). By the mid-1990s, over 2,700 hydraulic fracture stimulations had been completed (since the late 1980s) in diatomite at Lost Hills (Nelson et al., 1996). Subsequently, tens to hundreds of hydraulically fractured vertical wells were installed per year through at least 2005 (Hejl et al., 2007). Horizontal wells in the thinner oil zones along the margins of the field were first installed in the mid-1990s. The first test wells were oriented for transverse fractures (perpendicular to well direction). Based on the results, subsequent horizontal wells were installed oriented for longitudinal fractures (Emanuele et al., 1998).

Hydraulic fracturing of the siliceous shales in the Lost Hills field is reported as early as the 1960s as well (Al-Khatib et al., 1984). These shales are diatomaceous mudstones that recrystallized due to the large depth of burial, as discussed further in Section 4.2.2. Hydraulic fracturing during the 1960s through most of the 1970s, in an area with naturally-occurring fractures, did not significantly improve production. In 1979, oil was

found in nearby areas without natural fractures and was successfully produced after hydraulic fracturing. This was followed in the early 1980s by the installation of hundreds of vertical wells fractured over 30 to 120 m (100 to 400 ft) vertical intervals.

The reported hydraulic fracturing fluid types used since the 1970s are all water-based and predominantly gels. For instance, Hejl et al. (2007) reports the various gels used to fracture the diatomite at Lost Hills starting in the 1980s. Fracturing with gels is noted in the McKittrick field in the mid-1990s (Minner et al., 1997; El Shaari et al., 2005) and in the Belridge field at the same time (Allan et al., 2010). One of the Stevens Sand reservoirs at Elk Hills field was fractured with gels starting in the late 1990s (Agiddi, 2004, 2005).

A similar progression from vertical to horizontal wells occurred in the North Shafter field. Production was established from hydraulically fractured vertical wells starting in 1982, and installation of hydraulically fractured horizontal wells commenced in 1997 (Ganong et al., 2003). Horizontal wells in the similar Rose field nearby were oriented for longitudinal fractures, but fracturing resulted in complex fractures with both transverse and longitudinal components. This was attributed to almost equal stress in all directions (Minner et al., 2003). Production from these fields is from a quartz-phase shale (Ganong et al., 2003). This is a more recrystallized form of diatomite, due to greater burial depth, as explained in Section 4.2.2.

As described above, hydraulic fracturing has been used to produce oil from diatomite, opal CT and siliceous shale, and quartz-phase shale. These represent the various rock types from diatomite at different depths, indicating the broad range of applicability of hydraulic fracturing to this rock sequence. Besides diatomite and rock derived from diatomite, hydraulic fracturing has also been used in low-permeability sandstones. For instance, such rocks have been successfully targeted in the Elk Hills, North Coles Levee, and Mount Poso fields (Underdown et al., 1993; Agiddi, 2004; Evans, 2012).

For decades all the reported fluids have been water-based, but the type of fluid used has changed through time in some locations to better match conditions. For example, ungelled water was successfully used for fracturing in the Edison field. Ungelld water subsequently replaced the gels used for hydraulic fracturing previously in the Tejon field. The ungelld fractures provided economically viable results as opposed to the gelled fractures (Mathis et al., 2000). Research starting in 2002 led to switching from cross-linked gels, described in Section 2.3.2, to low-polymer-concentration gels to minimize plugging of the natural pores in a low-permeability sandstone reservoir in the Elk Hills field (Agiddi, 2005).

To develop a more comprehensive understanding of hydraulic fracturing activity over the last decade, well records were sampled to estimate the percent of all wells hydraulically fractured, the result of which was then used to extrapolate the number of hydraulically fractured wells in California. The well records in the sample were searched to identify wells in which hydraulic fracturing operations have occurred. Well records are publicly available from DOGGR in the form of scans without searchable text (DOGGR, undated).

Through application of optical character recognition software, DOGGR provided versions of the records with searchable text for all wells identified as first producing oil after 2001 outside of Kern County, and for a selected sample of such records inside Kern County (Bill Winkler, DOGGR, personnel communication). Presuming the 20% of the wells were fractured, the size of the well record sample size was selected to provide a 95% probability of the estimated proportion being within 2% of the actual proportion, using a finite population correction factor.

The well-record search provided information on the number of hydraulic fracturing operations over time. An operation consists of all the stimulation stages performed in a well during a single entry, typically over a period of hours to days. Records indicating that a well was hydraulically fractured were identified using the search term “frac”. The space after the term avoided occurrences of the term “fracture,” which appears in the template information on some forms, and consequently the term is not correlated with wells that have been hydraulically fractured. The term “frac” was found to correctly identify more such records of hydraulic fracturing than other potential terms, such as “fracture,” “stimulation,” “stage,” and “frack.” The few records containing the latter term also all included the term “frac”. Records containing “frac” were reviewed to determine if hydraulic fracturing indeed occurred. In some cases a record containing “frac” was for a well that was not hydraulically fractured because this term was also used in descriptions of geologic materials and the fracture gradient (the minimum fluid pressure per depth that will fracture the rock in a particular location). For Kern County well records, over 90% of the records containing “frac” indicated hydraulic fracturing had occurred. For all other counties as a group, fewer than 40% of the records containing “frac” indicated hydraulic fracturing had taken place.

Figure 3-1 shows the average annual number of wells with first production (in three different time periods) that have a record of hydraulic fracturing. This figure does not represent an estimate of the total amount of hydraulic fracturing activity, however, because not all hydraulic fracturing jobs were recorded in the well records, and this well-record search pertained only to production wells and did not include injection wells, which are also hydraulically fractured in some locations. Injection well records were not searched.

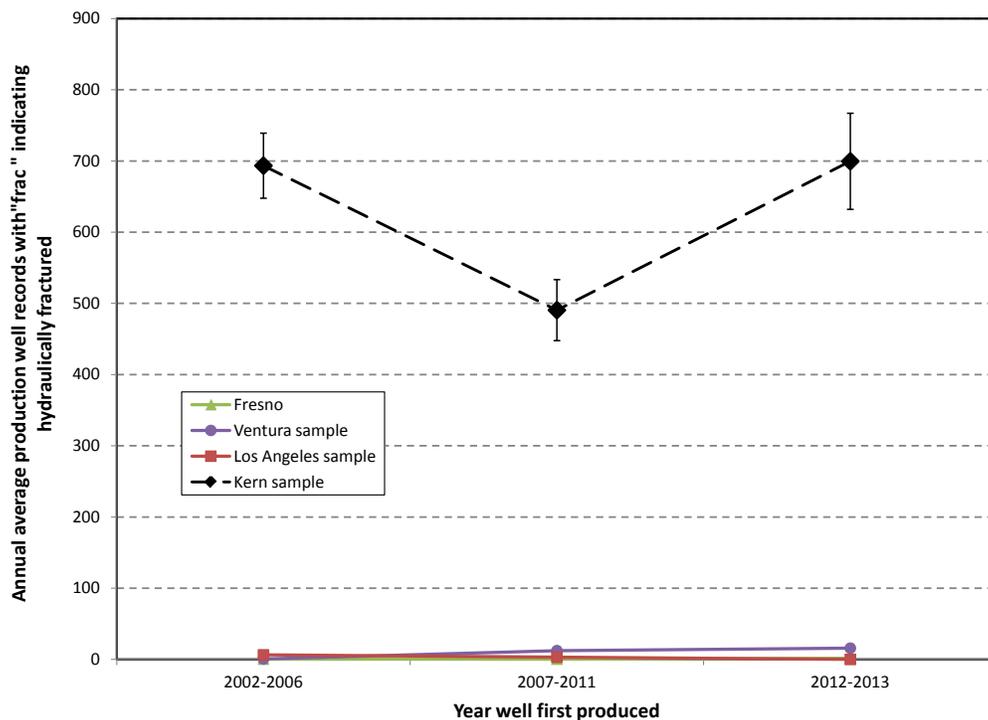


Figure 3-1. Average annual number of wells with first production in different time periods that were hydraulically fractured. There is a 95% chance that if all the well records had been searched rather than a sample, the average annual number of wells indicated as hydraulically fractured would be within the range indicated by the vertical bars.

Hydraulic fracturing occurred in Kings, Monterey, and Santa Barbara counties, in addition to those shown in Figure 3-1. Kings County is not shown on the figure because the average annual number of operations was less than two. For Monterey and Santa Barbara counties, records were available for a portion of all the wells. For the 2007-2011 time period in these counties, the search results from this well record sample and the size of the sample compared to the total number of wells indicate a 95% likelihood that the average annual number of hydraulic fracturing operations is fewer than two. In the other time periods for Monterey and Santa Barbara counties, and in all three time periods for Orange and San Luis Obispo counties, no hydraulic fracturing operations were identified in the available well records. However, because records for many wells in these counties were not available, the well record sample size is too small to provide confidence in a quantitative result.

Figure 3-1 indicates that about 60 production wells per month are fractured, with almost all this activity in Kern County. It also indicates that the number of recent hydraulic fracturing operations is similar to that before the recession in 2008. This contrasts with the fact that hydraulic fracturing activity increased substantially in other parts of the country.

3.2.2 Current Use of Hydraulic Fracturing

There is no comprehensive source of information on hydraulic fracturing activities in California. However, in addition to the results of the well-record search above, there are four useful sources of data regarding recent and pending hydraulic fracturing in California: FracFocus, FracFocus data compiled by SkyTruth, DOGGR GIS data files, and well stimulation notices. These are each described below.

FracFocus is a website used by the oil and gas industry to voluntarily disclose information about drilling and chemical use in hydraulic fracturing. The site was created in 2011 by two industry groups, the Interstate Oil and Gas Compact Commission, and the Groundwater Protection Council. Operators uploaded information on their hydraulic fracturing activities, which were (and still are) posted on the site as PDF documents for each individual fracturing job. The reports include a unique identifier for each well (an American Petroleum Institute (API) number), the well name and location, and information about the type and quantity of chemicals used. Many of the reports also include the volume of water used, although they do not report the source or type of water, i.e., operators do not report whether they used freshwater or produced water, nor whether water was withdrawn from a well, public supply, or another source. FracFocus provides voluntary disclosures that are not required to be either accurate or complete.

FracFocus data for hydraulic fracturing in California through the end of 2013, available as of January 21, 2014, were provided for this review by a DOGGR staff member with administrative access to the site (Vincent Aguseigbe, DOGGR, personal communication). The FracFocus data file provided was missing data for some fields. Upon inspection, it was determined much of the missing data were present in the individual PDF reports posted on the FracFocus website, and also available in the database compiled from the data available in FracFocus as of the end of July 2013 by the organization SkyTruth. This included data on hydraulic fracturing operations through April 2013. The information in the SkyTruth database was used to fill in almost all the missing records, with information from the PDFs on FracFocus entered for a few missing water volumes (Skytruth, 2013).

The third data source is geographic information system (GIS) data files maintained by DOGGR regarding oil, gas, and geothermal wells in California (DOGGR, 2014a). These files include some information on wells that was not available in the FracFocus database, such as whether a well had been directionally or horizontally drilled. These additional columns were added to the FracFocus database by joining records based on the API number for the well, which is a unique identifier for each well in the United States. The GIS well data file also included the dates that drilling and installation of some wells commenced, the measured depth of some wells, and voluntary identification of wells that were hydraulically fractured.

The fourth data source is well stimulation notices filed by operators posted by DOGGR as required by California Senate Bill 4 of 2013 (SB 4), which took effect on January 1, 2014. Under SB 4 operators must obtain permits at least 30 days prior to commencing a well stimulation treatment, and the notices must include basic information about water and chemical use (Pavley, 2013). Operators began filing notices in December 2013 for operations beginning in January 2014. Notices posted by DOGGR as received through January 15, 2014 are considered (DOGGR, undated).

The FracFocus database described above was the main source of information for analysis. However, these data are based on voluntary reports by operators and do not capture the full extent of hydraulic fracturing in California. There is evidence that the reports posted on FracFocus underestimate the extent of hydraulic fracturing occurring in California, especially before May 2012. FracFocus includes reports of 89 fractured wells in 2011, while the Western States Petroleum Association (WSPA) reports that during the same year, “WSPA member oil companies conducted some form of hydraulic fracturing operation on 628 wells” (WSPA, 2013). WSPA is the main oil and gas industry organization in California, and represents 80% of the state’s suppliers (Kiparsky & Hein, 2013, note 14, page 48). The number of hydraulically fractured wells reported by WSPA is equivalent to over 50 wells per month on average in 2011, This contrasts with about 15 wells per month hydraulically fractured in 2011 according to FracFocus, indicating FracFocus did not capture all hydraulic fracturing operations during that period.

Data from the first three sources were loaded into a relational database (Microsoft Access), to perform queries and summaries. The data were cleaned to remove obvious errors, including typos, missing information, and duplicates. In total, the database of known hydraulically fractured oil and gas wells in California between January 30, 2011 and December 31, 2013 included 1,478 records of hydraulically fractured wells, of which 1,453 were distinct wells (several wells have been fractured more than once).

Analyses of the FracFocus data along with DOGGR’s GIS well layer provide some understanding of recent hydraulic fracturing activity in California. The number of onshore hydraulic fracturing operations for oil per month reported in FracFocus and DOGGR’s well database is shown on Figure 3-2. For the DOGGR data, the date shown in Figure 3-2 is when drilling started, because that is the only date available. The fracturing operation presumably occurred sometime later.

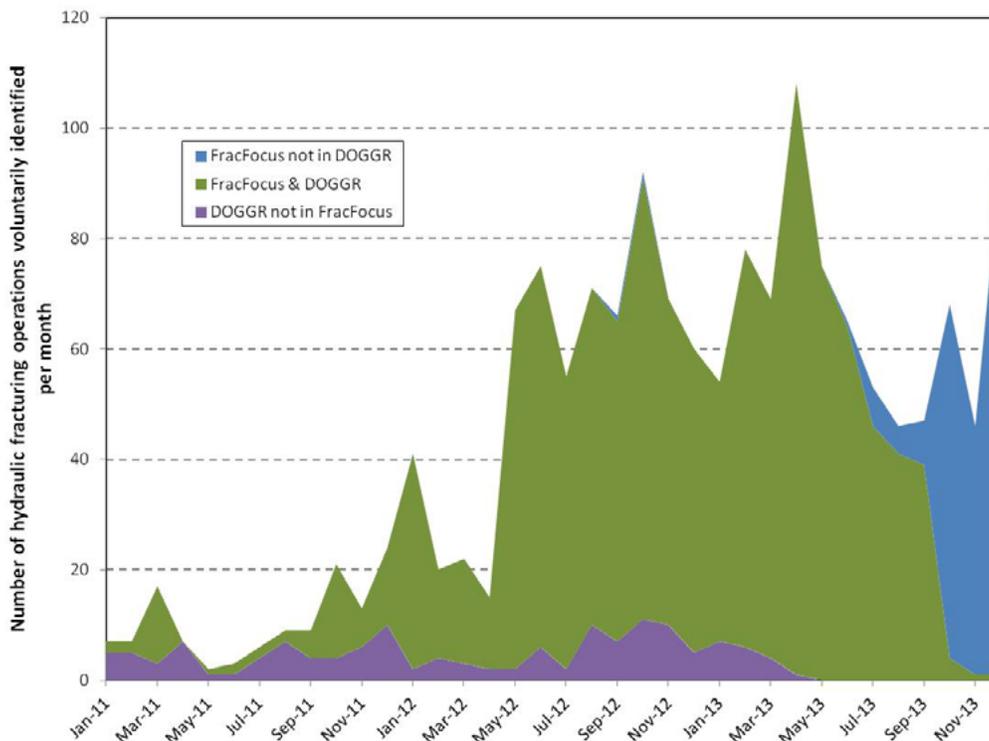


Figure 3-2. The number of fracturing operations per month summed from FracFocus and DOGGR’s well table.

Figure 3-2 shows a sharp increase in the number of hydraulically fractured wells reported to the FracFocus in mid-2012. This followed a DOGGR notice to operators in March 0123 requesting they voluntarily report data on their fracturing operations to FracFocus (Kustic, 2012). This provides further evidence that the FracFocus data do not capture all hydraulic fracturing activity, particularly in 2011 and 2012. Considering only the period after April 2012, the average number of reported operations is 69 per month.

Figure 3-3 shows the comparison between the FracFocus data and the results of the well-record search, accounting for the Kern County well-record sample proportion of one quarter for the 2012 to 2013 time period. Figure 3-3 shows the well-record search identified about 80% of the wells in FracFocus. The well-record search identified about 10% more wells compared to the number of hydraulic fracturing operations in FracFocus. Based on the FracFocus average of 69 wells per month, this suggests a total monthly activity of 76 operations.

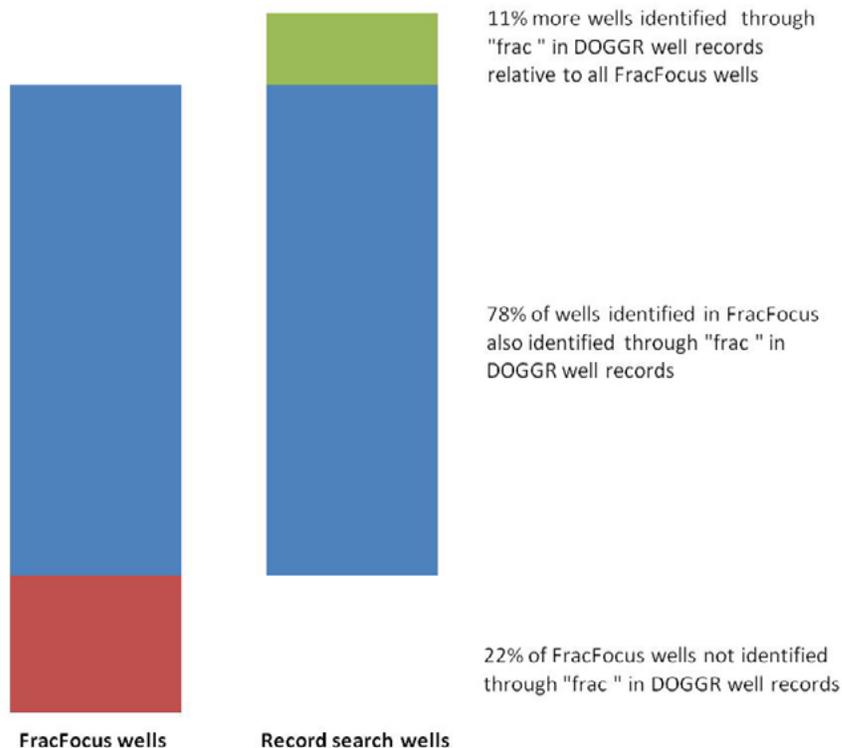


Figure 3-3. Overlap between wells indicated as fractured in FracFocus and in well records during May 2012 through October 2013, which is the period of greatest overlapping coverage between the two sources.

However, because this number is based on voluntary and incomplete reports, the count of hydraulic fracturing notices received by DOGGR provides a check. As of this writing, DOGGR has posted the notices it received in December 2013 and the first half of January 2014. DOGGR received 195 hydraulic fracturing notices in December. Of these 190 were approved and five were subsequently withdrawn. In contrast, 18 notices have been posted for the first half of January, but that number is low because DOGGR stopped approving submittals received without groundwater monitoring plans as of January 1, 2014 (Vincent Agusiegbe, DOGGR, personal communication). The number of notices submitted in December 2013 suggests the monthly average number of hydraulic fracturing events may be greater than 76 based on FracFocus and the well record search. Because of this, for the purposes of this study, the estimated monthly number of hydraulic fracturing events per month in California is taken as 100 to 150. For comparison, over one million hydraulic fracturing operations are estimated to have occurred throughout the United States (King 2012), with over 100,000 of these in recent years (Ellsworth 2013).

The December notice count suggests a number of operations per month two to three times as great as indicated by the voluntary data sources, if it is assumed that all these operations were to be carried out in January. However, while the notices must be submitted in advance of the fracturing operation by at least 30 days, a notice can be submitted some indeterminately greater amount of time in advance. The December notices include large groups of notices identical except for the well details, suggesting that operators submitted project plans for a period longer than a month. Doing so would provide some level of efficiency for the operator. Thus, the December notice count provides a high-side estimate of monthly activity for the post-SB 4 period.

All of the data sources also provide for estimating where hydraulic fracturing occurs. Joining FracFocus to DOGGR's GIS well data file provided information on the oil field where each well is located. This indicated that 93% of the wells in FracFocus are located in North and South Belridge, Lost Hills and Elk Hills fields on the west side of the southern San Joaquin Valley. Considering wells indicated as hydraulically fractured whose drilling started after April 2012 in DOGGR's GIS well files, 94% are in these four fields. From the well-record search, 87% of the wells identified as fractured with first production after 2011 were in these four fields, while 91% identified from the previous decade were in these fields. A total of 94% of the first 208 hydraulic fracturing notices posted (those listed as received through January 15, 2014) list these four fields. Consequently, all the data sources indicate that most of the hydraulic fracturing activity is in these four fields.

The three data sources (well-record search results, FracFocus, and DOGGR's GIS well data files) along with the literature identify 69 fields with a record of hydraulic fracturing out of the 303 onshore oil fields with field boundaries from DOGGR (DOGGR, 2014b). None of the data sources described above provides thorough identification of onshore oil fields that have been hydraulically fractured, and it is unlikely that they provide such thorough identification in combination. More fields have likely been hydraulically fractured than are shown in Figure 3-4. Ventura County was the only other county besides Kern with wells indicated by the hydraulic fracturing notices. Three notices were submitted for wells in Ventura County.

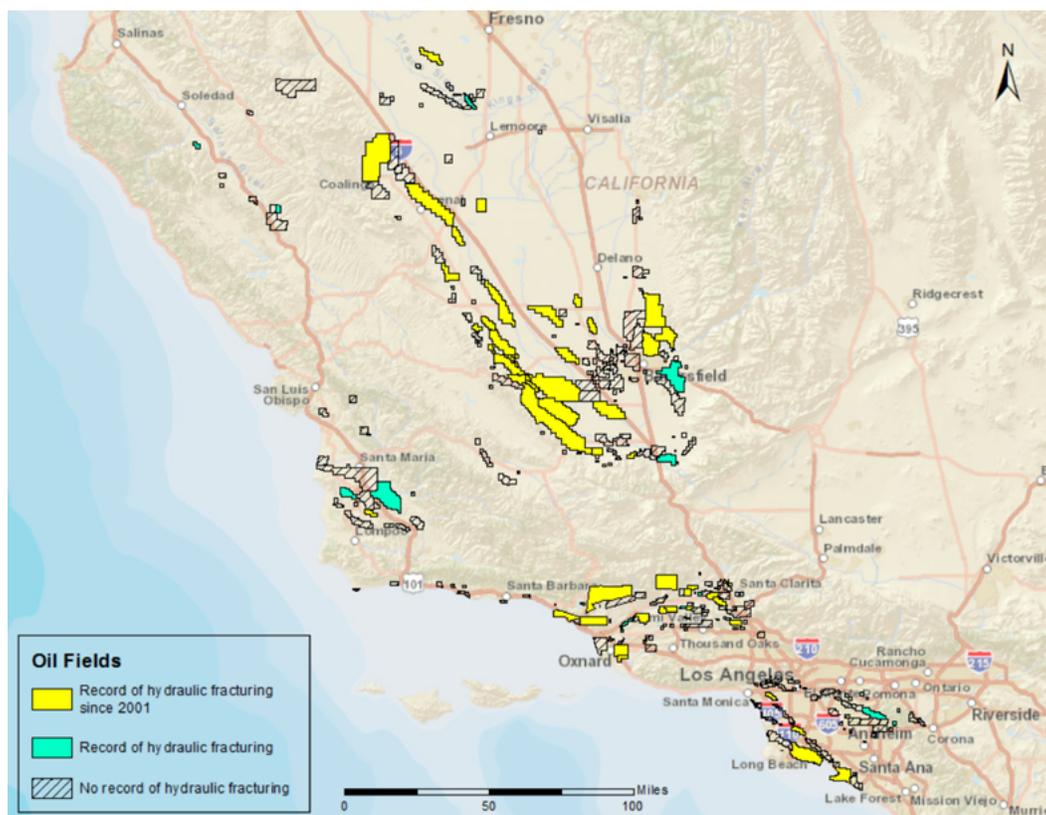


Figure 3-4. Onshore oil fields with a record of hydraulic fracturing.

3.2.3 Fluid Volume

Based on voluntary disclosures by operators in the FracFocus database, average water use for hydraulic fracturing in California was 490 m³ (130,000 gallons) per operation. This is similar to the average annual water use of 580 m³ (153,000 gallons) in each household in California over the last decade. This is based on residential water use of 0.54 m³ (143 gallons) per person per day (Department of Water Resources, 2013) and an average household size of 2.93 people (US Census Bureau, 2014).

There is considerable variation in the water use per operation, as shown on Table 3-1 and Figure 3-5. The minimum water use was 23 m³ (6,000 gallons) per well, and the maximum was 17,000 m³ (4.4 million gallons) per well. As a result, the coefficient of variation for these data is high (1.7), meaning that the standard deviation is larger than the mean, or that there is a large spread in the amount of water used. The 90% confidence interval for the mean water use is 470 to 540 m³ (120,000 to 140,000 gal) per well.

Table 3-1. Base water volume statistics from FracFocus and hydraulic fracturing notices.

Number of Records:	FracFocus Voluntary Reports (2011–2013)		Hydraulic Fracturing Notices (Dec. 2013 - Jan 2014)	
	Cubic meters	Gallons	Cubic meters	Gallons
	1,478		213	
Minimum	23	6,000	240	63,000
10%-ile	83	22,000	760	200,000
25%-ile	180	48,000	760	200,000
50%-ile (Median)	280	74,000	760	200,000
75%-ile	530	140,000	760	200,000
90%-ile	1,100	280,000	950	200,000
Maximum	17,000	4,400,000	1,800	250,000
Average (arithmetic mean)	490	130,000	790	210,000
Standard deviation	830	220,000	230	60,000
Coefficient of Variation	1.7	1.7	2.8	0.28

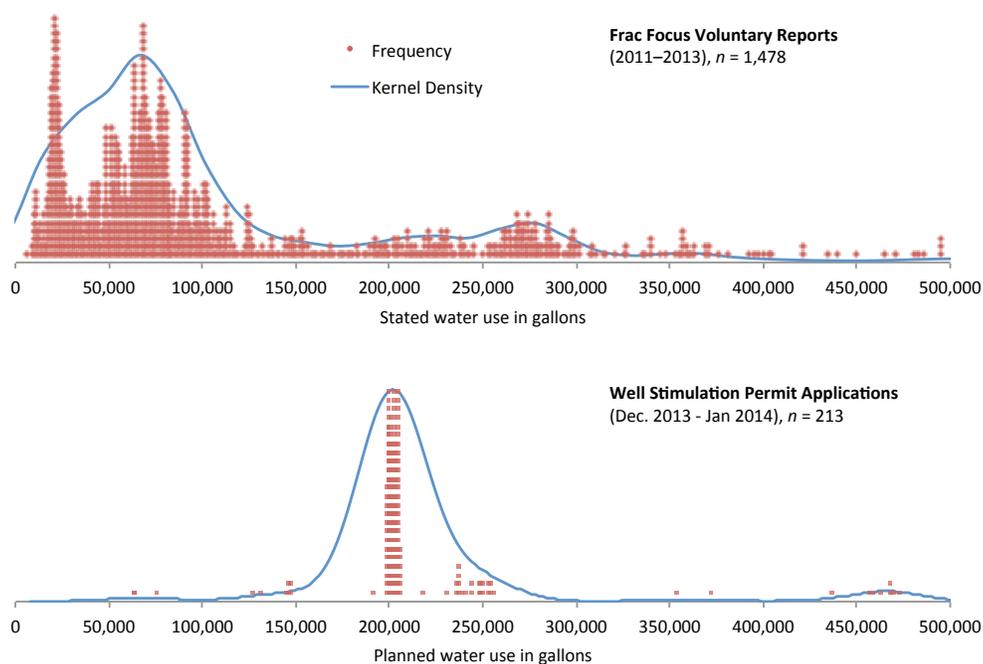


Figure 3-5. Water use per hydraulic fracturing operation in California according to (top) FracFocus voluntary reports and (bottom) hydraulic fracturing notices.

In Figure 3-5, each dot represents a single fracturing operation. The overlay line represents the smoothed data density. Note that the bulk of the reported water use from 2011 to 2013 in the FracFocus database is below 100,000 gallons per well, but that the data set is highly skewed with a “long tail,” or many high observations. Of the 1,478 FracFocus reports, there are 47 observations over 500,000 gallons per operation, and 11 observations over 1 million gallons per operation. The distribution is also represented in log space on Figure 3-6, which shows that it is relatively log normal, with some right skew due to the few highest values.

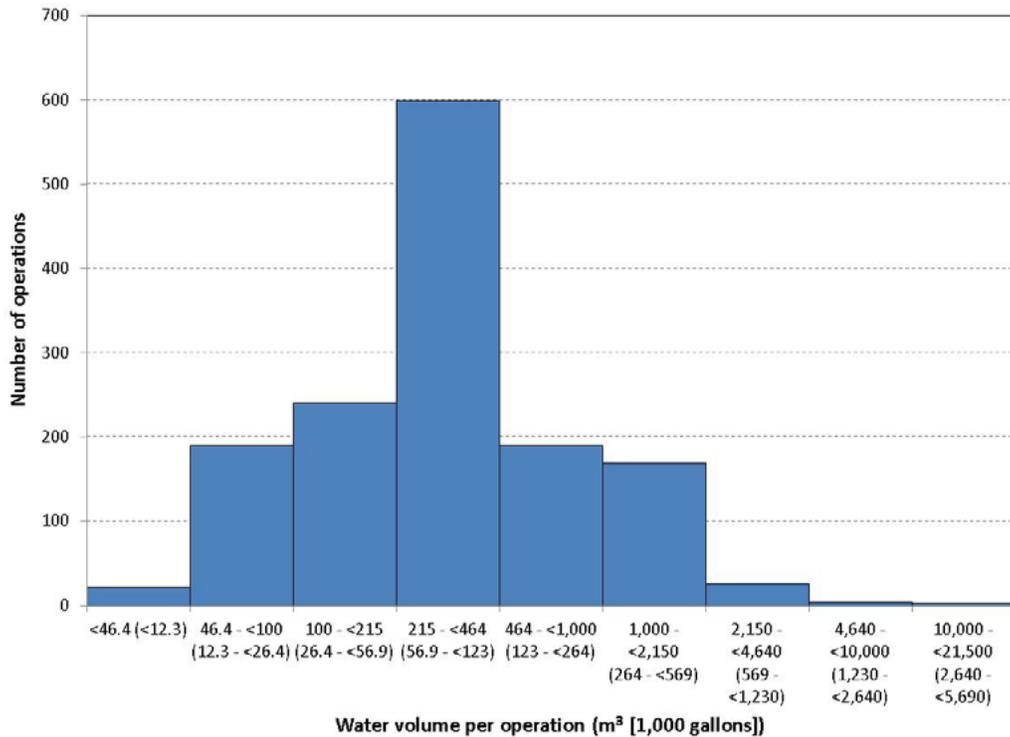


Figure 3-6. Distribution of water volumes in FracFocus per hydraulic fracturing operation.

Table 3-1 and Figure 3-5 summarize the water volume used per hydraulic fracturing operation according to two data sources. The notices contain a water-volume estimate because operators are required to file a water-management plan with the following information (California Public Resource Code Section 3160, subdivision (d) (1) (C)):

- i. An estimate of the amount of water to be used in the treatment. Estimates of water to be recycled following the well stimulation treatment may be included.
- ii. The anticipated source of the water to be used in the treatment.

- iii. The disposal method identified for the recovered water in the flowback fluid from the treatment that is not produced water included in the statement pursuant to Section 3227.

As indicated in Table 3-1 and Figure 3-5, planned future water use for hydraulic fracturing reported by operators is somewhat higher than historical water use over the last three years. Among the 213 notices for hydraulic fracturing, planned water use averaged 790 m³ (210,000 gallons) per operation, with a standard deviation of 230 m³ (60,000 gallons). Thus, the planned water use in the notices is higher than the historical average reported in the FracFocus database, but has a smaller variance.

Among the hydraulic fracture notices, many report the same planned water use. It is of note that one company, Aera Energy LLC, which submitted the majority of the hydraulic fracturing notices (174 of 213), included the identical water plan in 171 of those cases. This plan stated that “the maximum [emphasis added] volume of fresh water used in the treatment will be 4,800 barrels (201,600 gallons).” In this case, the planned water use of 763 m³ (201,600 gallons) per operation was entered in the database. Because this represents a maximum planned water use, it may bias the results upwards, causing an estimated higher average water use than will actually take place. Because the majority of hydraulic fracturing notices are exact copies of one another, they may not capture the variability in water use that is likely to occur in the field.

The relationship between water use and a number of independent variables (e.g., time, well depth, perforation length, region, and operator) was examined. It does not appear that there is a significant trend in water use over time as shown in Figures 3-7, nor does there appear to be a strong relationship between the volume of water used and the depth of the well as shown in Figure 3-8. Water use has varied widely from early reports in 2011 until the end of 2013, and there is not a statistically significant trend in water use with time. However, each of the four largest observations of water use (all over 11,400 m³ (3 million gallons)) occurred during the second half of 2013. It is not known whether these high outliers are isolated experiments or indicative of future trends.

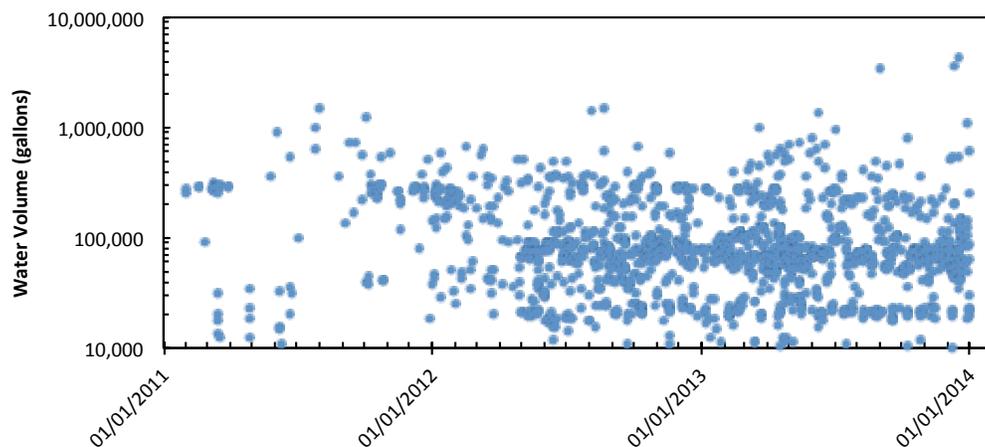


Figure 3-7. Time series of water volume used for each hydraulic fracture operation in California according to information voluntarily reported by operators to FracFocus during 2011-2013.

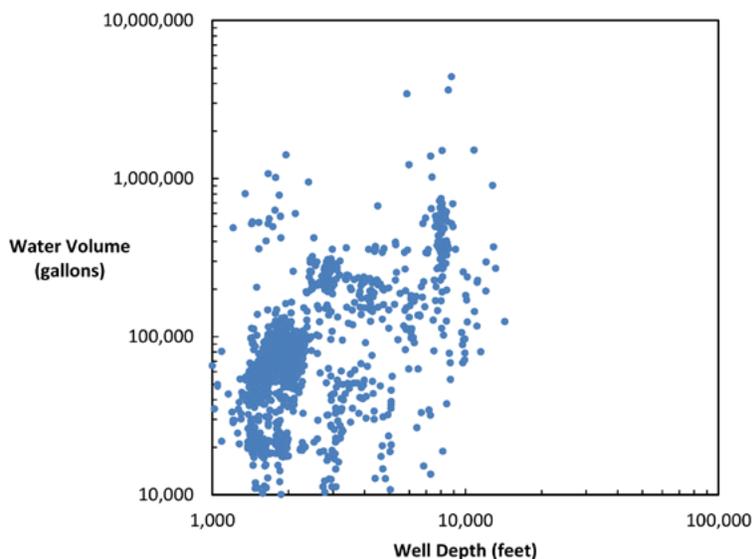


Figure 3-8. Volume of water used for each hydraulic fracture operation in California versus the absolute vertical depth of the well, according to information voluntarily reported by operators to FracFocus during 2011-2013.

The DOGGR well database contained data on well configuration for a total of 1,090 wells that are also listed in FracFocus. It was found that hydraulic fracturing operations in horizontal wells use more water on average in California than in directional and non-directional wells (DOGGR’s term for vertical wells). Average water use per operation for each well configuration is shown in Table 3-2. Water use for operations in directional wells was slightly higher on average than for wells that were non directional; however, the difference in the means is not statistically significant (according to a two-tailed t-test for difference in sample means, $P = 0.16$). Operations in horizontal wells use significantly more water than vertical wells (two-tailed t-test, $P < 0.001$); average water use in these operations is nearly three times higher than the water use for operations in other wells.

Table 3-2. Average water use per hydraulic fracture operation in wells in California by their directional drilling status

		Not directionally drilled	Directionally drilled	Horizontally drilled
Past Fracturing Activity in the FracFocus database	Number	213	833	44
	Water Use (m3)	370	420	0.17
	Stdev (m3)	350	500	1,000
	Water Use (gallons)	99,000	110,000	300,000
	Stdev (gallons)	92,000	130,000	270,000
Future fracturing activity from Well Stimulation Notices	Number	11	194	8
	Water Use (m3)	760	780	1,800
	Stdev (m3)	0*	130	40
	Water Use (gallons)	200,000	210,000	460
	Stdev (gallons)	0*	35,000	11,000

** Aera Energy submitted each of the 11 notices for non-directionally drilled wells to be hydraulically fractured, and states in each notice that “the maximum volume of fresh water used in the treatment will be 4,800 barrels,” or 201,600 gallons, thus there is no variability among these 11 observations.*

The average volumes from both FracFocus and the notices for California hydraulic fracturing operations contrast with the average volume per operation of 16,000 m³ (4.25 million gallons) reported by Nicot and Scanlon (2012) for fracturing horizontal wells in the Eagle Ford in Texas. Table 3-2 indicates part of this difference is caused by the predominance of hydraulic fracturing of vertical and directional wells over horizontal wells in California, while horizontal wells are predominant in the Eagle Ford. This is particularly the case as review of a small sample of directionally-drilled-well records indicates they are typically vertical or close to vertical through the producing zone. The well path primarily deviated from vertical above the production zone to offset the location at which the well entered the producing zone from the location where the well was drilled. The well records available from DOGGR for the wells indicated as horizontal

by DOGGR were also examined. Only half of these wells are actually horizontal according to the records. The average hydraulic fracturing water volume per operation in just those wells is 1,700 m³ (450,000 gallons) with a standard deviation of 170 m³ (48,000 gallons). This volume, as well as that listed on Table 3-2 from the hydraulic fracture notices for horizontal wells, are both about one-tenth the average volume per well in the Eagle Ford.

Average water use intensity per unit length of well hydraulically fractured was estimated using information in the hydraulic fracturing notices submitted by operators to DOGGR. Most of the notices for vertical and directionally-drilled wells provide the anticipated measured top and bottom depth of the stimulation interval, as well an estimated water volume. The average intensity is given on Table 3-3. Water use intensity was also calculated for the 21 wells with water usage in FracFocus indicated as horizontal in DOGGR’s well file and confirmed as horizontal in each well’s record. The hydraulic fracturing treatment length is not available for these wells, so the intensity calculation used the distance between the shallowest and deepest production casing perforations listed in well records. This small data set contained a high outlier where the water use intensity (water volume per well length stimulated) was 13 m³/m (1,000 gallons per foot, or gpf). The average water use intensity for these horizontal wells, excluding this high observation, is also given on Table 3-3. The perforated length explains about 40% of the variability in water use among the remaining 20 operations. The comparison to average water use intensity in the Eagle Ford and Bakken on Table 3-3 indicates intensities in California are similar to gels in the Bakken, but considerably less than the average intensity in the Eagle Ford and slickwater in the Bakken.

Table 3-3. Average water use intensity from hydraulic fracturing notices and FracFocus horizontal well disclosures compared to average intensity in the Eagle Ford (Nicot and Scanlon, 2012) and for different fluid types in the Bakken (described in section 2.3.7)

	Notices	FracFocus- horizontal	Eagle Ford	Bakken		
				Cross-linked	Hybrid	Slickwater
m ³ /m (gallons per ft)						
Average intensity	3.0 (244)	2.3 (190)	9.5 (770)	3.4 (277)	3.9 (315)	13.2 (1063)
Standard deviation	0.9 (74)	1.6 (130)	3.4 (277)			

The water volume per hydraulic fracture operation was mapped to determine whether there are geographic patterns to water use. There are several apparent clusters of similar water use, as shown in the example in Figure 3-6. This figure shows a cluster of water volumes per operation of 950 m³ to 1100 m³ (250,000 to 300,000 gallons) per well. These wells are operated by XTO Energy/Exxon Mobil. Operations immediately to the north and south have a water use averaging about 190 m³ (50,000 gallons) and were

conducted by Area Energy LLC. Another cluster of high-water-use operations occurs near the border of Belridge North and Belridge South fields and were conducted by BreitBurn Energy Partners L.P.

The FracFocus data indicate that the water used in each fracturing operation varies by company and that the operator of a well is a more important predictor of water use than any other factor, as shown in Table 3-4, which ranks companies from high to low in terms of their average per-operation water use. A statistical test (single factor or one-way ANOVA) among the six companies with more than 10 hydraulically fractured wells indicates water use varies significantly by company (P-value less than 10^{-56}). In fact, the operator is a better predictor of water use per operation than any other factor considered. This is consistent with the statement by Allan et al. (2010) that fracturing of diatomite has become relatively standardized within companies, but varies from company to company.

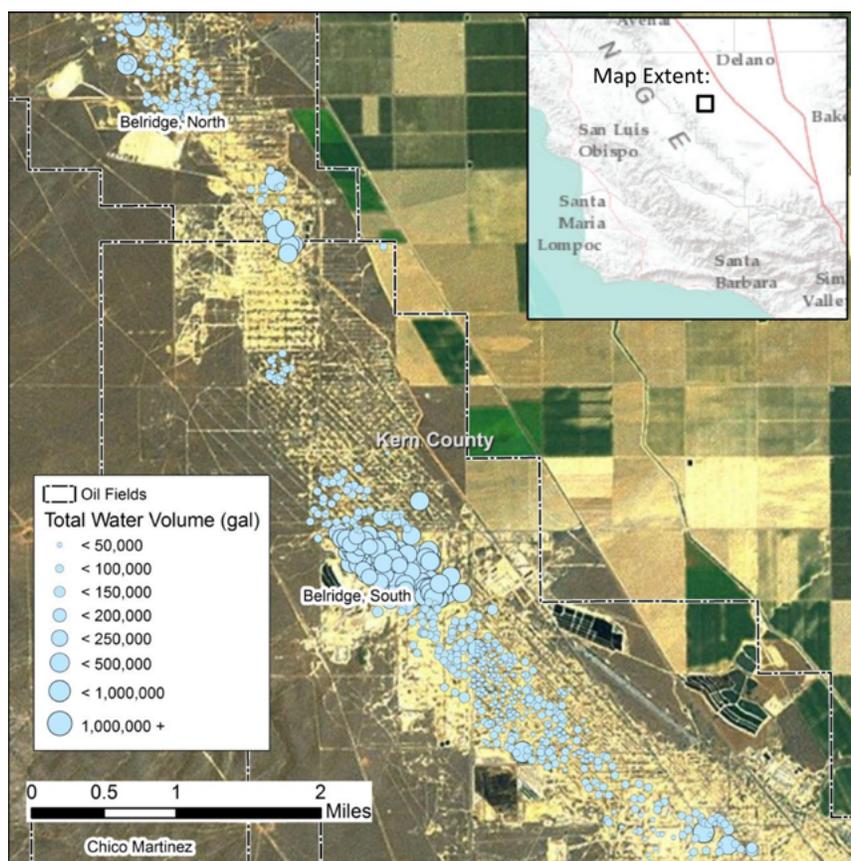


Figure 3-9. Hydraulically fractured oil wells in the Belridge North and Belridge South fields in Kern County, California. The diameter of the point is proportional to the volume of water used in hydraulic fracturing.

Table 3-4. Water volume used per hydraulic fracturing operation per operator according to data voluntarily reported to FracFocus for January 2011 to December 2013.

Operator	Number of operations reported	Water use per operation (million gallons)		
		Min	Average	Max
Seneca Resources Corporation	18	0.27	0.60	3.4
BreitBurn Energy Partners L.P.	8	0.26	0.28	0.36
XTO Energy/ExxonMobil	106	0.110	0.27	0.3
Chevron USA Inc.	38	0.03	0.26	1.50
Occidental Oil and Gas	284	0.010	0.23	4.4
Plains Exploration & Production Company	2	0.13	0.15	0.17
Aera Energy LLC	999	0.0060	0.077	1.4
The Termo Company	3	0.038	0.071	0.11
Venoco Inc	20	0.011	0.035	0.23

3.2.4 Fluid Type

In this section, the chemical composition of hydraulic fracturing fluid in use in California is described. Chemical constituents were available in the FracFocus data set for 1,386 onshore oil hydraulic fracturing operations. Guar gum, a gelling agent, was included in over 96% of the operations; borate compounds, which serve as cross linkers, are included in 90% of the operations. In addition, 210 of the 213 hydraulic fracturing notices received by DOGGR before 16 January 2014 indicate the use of a gelled fluid based on the components listed. These data indicate hydraulic fracturing in California is primarily performed with gels, and the gels are predominantly cross-linked. More information on fluid composition in well stimulation fluids is given in Section 5.1.2.1.

Of the 1,386 operations with chemical data, 3.4% included a friction reducer, indicating an operation involving slickwater fracturing. This includes all operations listing acrylimide compounds, as well as those involving compounds with “friction reducer” listed as the purpose. Compounds with this purpose listed included petroleum distillates (which are likely a carrier fluid in an additive with another friction-reducing compound) and undisclosed constituents.

There is a strong correlation between water volume and the type of hydraulic fracturing fluid used. The average water volume for operations involving slickwater is 2,200 m³ (590,000 gallons), which is almost four times the average volume for all operations. Additionally, the three highest volume events (12,900, 13,600 and 16,700 m³ (3.4, 3.6 and 4.4 million gallons)) involved slickwater.

3.3 Acid Fracturing

No reports of the use of acid fracturing in California were found in the literature. As described in Section 2.3.4, acid fracturing is used in carbonate reservoirs (which includes dolomite). The only such reservoirs identified in California were in some of the fields in the Santa Maria basin and possibly the Los Angeles basin (Ehrenberg and Nadeau, 2005; see Section 4.7 for basin locations). The fields in the Santa Maria basin consist of naturally fractured dolomite (Roehl and Weinbrandt, 1985). The dolomite reservoir in one of these fields (West Cat Canyon) was characterized as producing oil from the natural fractures (Roehl and Weinbrandt, 1985).

The highest concentration of hydrochloric acid in hydraulic fracturing fluid disclosed in the FracFocus data set is less than 3.5%, and the highest concentration of hydrofluoric acid is less than 0.5%. These concentrations are too low to indicate an acid fracturing operation (Economides et al., 2013). In addition, nine of the ten operations with greater than 1% hydrochloric acid in the hydraulic fracturing fluid also include guar gum and borate cross-linkers. Four of these, along with the one operation without guar gum or borate cross linkers, also included polyacrylamide or another component identified as a friction reducer.

The three hydraulic fracturing notices received from Occidental Petroleum by DOGGR on 31 December 2013 specify a sandstone matrix acidizing fluid, indicating these planned stimulations are acid fracturing. This is a novel type of stimulation relative to stimulation approaches characterized in the literature. The fluid components, including hydrochloric acid and ammonium bifluoride, are the same as those listed on about half of the matrix acidizing notices submitted by Occidental and received by DOGGR on or before 15 January 2014. The planned stimulations are in the Elk Hills field at vertical depths ranging from 2,100 m to 3,224 m (6,888 to 10,575 ft).

The estimated water volume for these three planned stimulations ranges from 493 to 760 m³ (130,000 to 200,000 gallons). This is less than or almost equal to the average volume for hydraulic fracturing from the notices. Based on the top and bottom depth of the treatment interval listed, the water use per well length ranges from 0.60 to 0.74 m³/m (48 to 72 gpf). This volume per treatment length is less than that from the matrix acidizing notices given in Section 3.3.3. This raises the question of whether the notices that indicate acid fracturing are actually matrix acidizing, with the wrong box checked on the notice. If these notices really do represent acid fracturing, the treatment volumes per treatment length suggest limited penetration into the reservoir. Another possibility is that the treatment is applied to only a portion of the well length implied by the top and bottom depth of the treatment interval listed on the notices, such as if multiple short intervals were treated within that depth range.

3.4 Matrix Acidizing

3.4.1 Historic Use of Matrix Acidizing

The use of sandstone matrix acidizing for well stimulation in the Monterey Formation is relatively recent. The first and most detailed report of production enhancement as a result of high-volume sandstone acidizing for onshore production from the Monterey is from Rowe et al. (2004) for the “NA shale” reservoirs at Elk Hills. A series of 21 horizontal wells were drilled and stimulated between 1999 and 2001. The treatment process started from low-volume sandstone acidizing treatments, first using 0.0248 m³/m (2 gpf) of production interval with a 17% HCl acid. Diversion was accomplished by a mechanical method employing coiled tubing. Subsequent wells were treated with an increased volume of 0.35 m³/m (28 gpf). Apparent damage due to the water-based drilling mud led to drilling with an oil-based mud. Despite the use of a nondamaging mud, HCl acid treatments were effective for roughly doubling oil production. Subsequent wells were then treated with 17% HCl followed by a 12% HCl, 3% HF acid, with 0.256 m³/m (20.6 gpf) and 0.373 m³/m (30 gpf), respectively. Treatment volumes were increased to 1.86 m³/m (150 gpf) of the 12% HCl, 3% HF acid, resulting in nine-fold oil production increases. Treatments were eventually tested with 3.1 m³/m (250 gpf) of 17% HCl and 3.1 m³/m (250 gpf) 12% HCl, 3% HF, which was found to be optimum. The reported recovery of spent acid from the formation was 50%, either by natural flowback or using nitrogen gas lift. Although fracture characterization was not presented, Rowe et al. (2004) concluded that the acidizing treatment must have resulted in the mitigation of drilling damage from natural fractures. While this is possible, the use of nondamaging drilling muds in some of the wells and the positive response to acidizing suggests that the treatment may also be opening up natural fractures plugged with some type of natural fracture-filling material.

The use of successful sandstone acidizing at Elk Hills is also reported by Trehan et al. (2012), who employed a high-rate injection (MAPDIR)/foam diversion approach to the acid treatment. The treatment was applied to intervals of 457 to 610 m (1,500 to 2,000 ft) in length. A foamed HCl/HF acid was successfully applied to producing wells in shallow sands with steam injection in the South Belridge field in the early 1990s as an improvement over previous sandstone acidizing with lower concentrations and volumes per treatment length in the same reservoir (Dominquez and Lawson, 1992). The more successful treatment used 1.9 m³/m (150 gallons per ft) of 15% HCl and 5% HF.

The possibility of the high-volume sandstone acidizing treatment in naturally fractured siliceous shales is supported by Kalfayan (2008), who states, “There are few cases requiring greater volumes of HF than 1.86 to 2.48 m³/m (150 to 200 gpf). These are limited to high-permeability, high-quartz sands and fractured formations, such as shales, where high volumes of acid can open fracture networks deeper in the formation”. Similar conclusions were reached by Patton et al. (2003), who utilized sandstone acidizing for offshore production from the Monterey. The hypothesis for the improvement in production is that

the HCl/HF treatment is effective at removing clay and chert from natural fractures and improving permeability of the fracture system. However, note that the injection volumes cited by Patton et al. (2003) are not large, only 0.248 m³/m (20 gpf) for the 12%/3% HCl/HF acid.

A review of stimulation methods in the Monterey Formation by El Shaari et al. (2011) provides an alternative view that sandstone acidizing in the Monterey is effective at removing formation damage in fractures, but that good fracture-network permeability must exist naturally beyond the near-wellbore region if the treatment were to result in high oil production rates. For poorly fractured zones, such as at Elk Hills, El Shaari et al. (2011) postulate that either the treatment provides improved connection between the well and fractured calcareous intervals, or that the treatment in long production intervals characteristic of the Monterey, such as reported by Trehan et al. (2012), can significantly boost the overall magnitude of production, if not provide a large increase in the stimulation ratio.

A different acid system has been applied to the Stevens Sandstone in the North Coles Levee field in the early 1980s and continuing at least through the early 1990s (Hall et al., 1981; McClatchie et al., 2004). Termed “sequential hydrofluoric acid”, the system involves alternating injection of HCl and ammonium fluoride. These react on clay surfaces producing HF, thus targeting the fine-grained material in the sandstone for dissolution. The HCl concentration used in these treatments was 5%. Typical treatment volumes were 36 m³ (9,750 gallons). The typical treatment volume per well length was 0.44 m³/m (49 gallons per ft). This treatment resulted in an approximately four times larger increase in production compared to stimulation with an HCl and HF mix (Marino and Underwood, 1990).

3.4.2 Current Use of Matrix Acidizing

The only data on matrix acidizing currently comes from the matrix-acidizing notices submitted to DOGGR by operators. A total of 22 notices were received by DOGGR in December 2013 after the 11th and 14 were received in January 2014 before the 12th of that month. All the notices were for stimulations in the Elk Hills field. Ten of the notices received in January were subsequently withdrawn for unknown reasons, although this may have resulted from DOGGR’s not approving submittals without groundwater monitoring plans after January 1, 2014 (Vincent Agusiegbe, DOGGR, personal communication), rather than from the operators deciding that the stimulations were not desired. Given this uncertainty, the suggested activity rate is 30 matrix-acidizing operations per month.

3.4.3 Fluid Volume

Water use for matrix acidizing is listed on the notices. Planned water use ranged from 29 to 550 m³ (8,000 to 140,000 gallons), with an average of 160 m³ (42,000 gallons). The 90% confidence interval for the mean water use, based on 36 notices, is 120 to 200 m³

(31,000 to 51,000 gallons). Based on the notices that list top and bottom depth of the treatment interval, the average water use per well length and standard deviation are 1.7 m³/m and 1.5 m³/m (140 and 123 gallons per ft), respectively. These volumes are in the higher treatment range, suggesting treatment of fractured formations based on the discussion in Section 3.3.1.

3.4.4 Fluid Type

All the matrix-acidizing notices indicated use of HCl. About half of the treatments included HF and half included ammonium bifluoride. However, ammonium bifluoride produces HF acid when mixed with HCl acid (McClatchie et al. 2004). The chemicals included in the acidizing fluids (according to the notices) are further assessed in Section 5.2.1.

3.5 Conclusions

Available data suggest that present-day well stimulation practices for oil production in California differ significantly from practices in states such as North Dakota and Texas. For example, California hydraulic fractures tend to use less water and the wells tend to be more vertical. Large-scale application of high-fluid-volume hydraulic fracturing has not found much application in California, apparently because it has not been successful. As pointed out in Section 4, the majority of the oil produced from fields in California is not from the shale source rock (i.e., shale in the Monterey Formation), but rather from reservoirs containing oil that has migrated from source rocks. These reservoirs do not resemble the extensive, and continuous shale layers that are amenable to oil production with high water –volume hydraulic fracturing from long-reach horizontal wells, such as found in North Dakota.

Hydraulic fracturing has been the main type of well stimulation applied in California to date, based both on the total number of wells and fields where it has been used based on the literature and available data. Data indicate that hydraulic fracturing is performed in more than 76 wells per month on average, and perhaps up to 190 wells in some months. Given this range, hydraulic fracturing of 100 to 150 wells per month is a reasonable estimate.

Most of this fracturing occurs in the southwestern San Joaquin Valley in Kern County. For instance, 85% or more of recent hydraulic fracturing as well as fracturing over the last decade has occurred in the North and South Belridge, Elk Hills and Lost Hills fields in this area.

Data indicate average water use per well of 490 m³ (130,000 gallons) to 790 m³ (210,000) per hydraulic fracture operation. This is considerably less than in other hydraulically fractured plays in the United States. For instance, average water use per operation in the Eagle Ford in Texas is 16,000 m³ (4.25 million gallons). This results in part from the predominance of fracturing in vertical wells, which have shorter treatment intervals in California, as compared to the predominance of horizontal wells in major unconventional oil plays like the Eagle Ford and Bakken.

Water use per treatment length is also lower in California than elsewhere. The average and standard deviation water use in a set of horizontal wells disclosed as fractured is 2.3 m³/m (190 gpf). The average value from hydraulic fracturing notices is 3.0 m³/m (240 gpf). This compares to an average of 9.5 m³/m (770 gallons/ft) in the Eagle Ford (Nicot and Scanlon, 2012) and 3.4 m³/m (280 gallons/ft) for cross-linked gel, 3.9 m³/m (320 gallons/ft) for hybrid gel and 13 m³/m (1100 gallons/ft) for slickwater used in the Bakken, as described in section 2.3.7.

As indicated by the information from the Bakken, as well as engineering guidance discussed in Section 2.3.2, gels are associated with lower volumes per treatment length than slickwater, and cross-linked gel is associated with the least water volume among the gel types. The predominant fracturing fluid type in California is gel, of which most is cross-linked.

Acid fracturing is a small fraction of reported well stimulations to date in California. Acid fracturing is usually applied in carbonate reservoirs and these are rare in California. Matrix acidizing has been used effectively but rarely in California. These technologies are not expected to lead to major increases in oil development in the state. As explained in Chapter 2, these technologies increase the natural permeability of reservoirs consisting of silicate minerals only a limited amount.

The use of matrix acidizing is reported in far fewer fields in the literature than is hydraulic fracturing and the number of notices submitted for use of this technology is a small fraction of the number submitted for hydraulic fracturing. A total of 36 notices were received in the month from submittal of the first notice. All the notices were for stimulations in the Elk Hills field. Ten of the notices were subsequently withdrawn, but the timing suggests they may have been withdrawn due to action by DOGGR rather than because the operator did not want to perform them. Given this uncertainty and short timeline, the number of matrix-acidizing stimulations per month is estimated at 30.

Proposed water use for matrix acidizing on the notices averaged 160 m³ (42,000 gallons) per operation. The volume per treatment length from the notices averaged 1.7 m³/m (140 gallons per ft). This is somewhat less than for hydraulic fracturing, but in the higher part of the range identified for matrix-acidizing stimulations in general. This suggests that the treatments are targeted more toward treating natural fractures than the rock matrix (pores in the rock itself).

References to acid fracturing in California were not identified in the literature. Section 2.3.4 indicates that it is only applied in carbonate reservoirs. Only a few such reservoirs were identified in California, and these are naturally fractured, suggesting that acid fracturing is not applicable. However, three hydraulic fracturing well stimulation notices for wells in the Elk Hills field specify use of an HCl and HF mix, indicating acid fracturing. The minimum and maximum water volumes per treatment length implied by the three notices are 0.60 and 0.74 m³/m (48 and 72 gpf), respectively. This is smaller than indicated by the notices for matrix acidizing, and far less than the water use intensities for hydraulic fracturing. This suggests the treatment extent relative to the well is quite limited.

3.6 Acknowledgments

Staff at DOGGR and the California Department of Conservation (DOC) advised on and provided much of the data analyzed in this section, for which the authors are grateful. In particular, Bill Winkler of DOGGR patiently worked with the authors to develop a well-record sampling plan for assessing hydraulic fracturing activity over a longer period than available from FracFocus. He then arranged for the selected well records to be processed with text recognition software, in order to make them searchable, and then provided the records. Vincent Agusiegbe of DOGGR provided data output from FracFocus that made possible the inclusion of its data for the period after May 2013 in the analyses presented here. Undoubtedly, there were many DOGGR and DOC staff that participated in these efforts that are unknown to the authors, but we extend our appreciation.

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